COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Western Massachusetts Electric Company	)	D.T.E.97-120
Electric Restructuring Plan	)	

DIRECT TESTIMONY OF DAVID J. EFFRON

on behalf of

THE OFFICE OF THE ATTORNEY GENERAL

OCTOBER, 1998

I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and business address.

A. My name is David J. Effron. My business address is 386 Main Street, Ridgefield, Connecticut.

Q. What is your present occupation?

A. I am a consultant specializing in utility regulation.

Q. Please summarize your professional experience.

A. My professional career includes nineteen years as a regulatory consultant, two years as a supervisor of capital investment analysis and controls at Gulf & Western Industries and two years at Touche Ross & Co. as a consultant and staff auditor. I am a Certified Public Accountant and I have served as an instructor in the business program at Western Connecticut State College.

Q. What experience do you have in the area of utility rate setting proceedings?

A. I have analyzed numerous electric, telephone, gas and water rate filings in different jurisdictions. Pursuant to those analyses I have prepared testimony, assisted attorneys in rate case preparation, and provided assistance during settlement negotiations with various utility companies.

I have testified in over one hundred cases before regulatory commissions in Alabama, Colorado, Connecticut, Florida, Georgia, Illinois, Indiana, Kansas, Kentucky, Maryland, Massachusetts, Missouri, New Jersey, New York, North Dakota, Ohio, Pennsylvania, Rhode Island, South Carolina, Texas and Virginia.

As a result of my work with the Rhode Island Division of Public Utilities and Carriers in regard to the restructuring plans of Narragansett Electric Company (an affiliate of Massachusetts Electric Company) and Blackstone Valley Electric Company and Newport Electric Company (affiliates of Eastern Edison Company), I am familiar with those restructuring plans, which are similar in most respects to the restructuring plans of their Massachusetts affiliates. Further, because parties to the Massachusetts settlements also participated in the settlement negotiations that I attended, I also became familiar with the formula for the transition charges for the Massachusetts companies during the course of the those negotiations.

Q. Please describe your other work experience.

A. As a supervisor of capital investment analysis at Gulf & Western Industries, I was responsible for reports and analyses concerning capital spending programs, including project analysis, formulation of capital budgets, establishment of accounting procedures, monitoring capital spending and administration of the leasing program. At Touche Ross & Co., I was an associate consultant in management services for one year and a staff auditor for one year.

Q. Have you earned any distinctions as a Certified Public Accountant?

A. Yes. I received the Gold Charles Waldo Haskins Memorial Award for the highest scores in the May 1974 certified public accounting examination in New York State.

Q. Please describe your educational background.

A. I have a Bachelor's degree in Economics (with distinction) from Dartmouth College and a Masters of Business Administration Degree from Columbia University.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Office of the Attorney General.

Q. What is the purpose of your testimony?

A. My testimony addresses the determination of the transition charge ("TC") for Western Massachusetts Electric Company ("WMECO" or "the Company") to be implemented in association with its electric restructuring plan. In particular, I address what elements should and should not be included in the transition charge and how those elements should be computed. I have also prepared schedules that show the effect of my recommendations.

Q. What areas do you address in your testimony?

A. I address the following areas:

A. General
   1. Basis of Transition Charge
   2. NUG&T effect on WMECO cost responsibility

B. Fixed Costs in TC
   1. Recovery of Millstone Costs
   2. Regulatory Assets
      a. Deferred fuel costs

b. Return on deferred nuclear outage

c. Recognition of pension overfunding (FAS 87)

d. Return on FAS 106 and FAS 87

e. Method of recognizing FAS 109

f. Prior Spent Nuclear Fuel

3. Standard offer deferral

C. Return on Unamortized Fixed Costs

1. Update of capital structure

2. Update of cost of debt

3. Update of cost of preferred stock

4. Determination of return on equity

5. Income tax rate

6. Calculation of deferred tax offset

D. Variable Costs in TC

1. Generation operating costs

2. Unavoidable nuclear costs

3. Calculation of claims, net of recoveries

E. Potential Subsequent Adjustments to TC

1. Lost revenue formulation

2. True-up for "lost ROE"

3. True-up to FAS 106, FAS 87

F. Other Issues Affecting TC

1. Rate path vs. inflation cap

2. Effect of securitization, return past 2009

3. Nuclear PBR

4. Incentive formula

In addressing these areas, I occasionally compare the treatment being proposed by WMECO to that adopted by Massachusetts Electric Company ("MECO") and/or Eastern Edison Company ("EECO"). As the restructuring plans for those companies are the results of settlements, I understand that their TC formulations are not binding on WMECO. However, I believe that, given the amount of thought and work that went into the development of the TC for MECO and EECO, in reviewing WMECO's TC formula, the method adopted by those companies is a relevant consideration. I have reviewed the Boston Edison Company ("BECO") restructuring settlement, and I also occasionally compare WMECO's presentation to that of BECO, which I also believe is relevant to the consideration of WMECO's transition charge formula. Indeed, WMECO itself appears to implicitly acknowledge the relevance of these settlements in its application, stating in the covering letter that in submitting its plan it "has the benefit of reviewing ... the submittals of other Massachusetts electric companies" including MECO, EECO, and BECO and that the "resolution of most issues is identical to those of the other settling companies". As I believe that the transition charge formulae used by those companies are reasonable and fair to all parties, I agree that the resolution of most issues where applicable should be identical, and it is in this spirit that I refer to the terms of the TC calculation for other companies that have submitted settlements.

Q. Is any of your testimony based on an audit or a review of the prudence of the plant costs that WMECO is seeking to include in the calculation of the TC?

A. No. I have not conducted a full audit of the costs that WMECO is seeking to recover, nor have I conducted a prudence review of capital additions since 1991 or other elements of WMECO's plant costs. It is my understanding that these issues will be addressed in the second phase of these proceedings. My testimony addresses the structure of the TC and the costs that should be included, or, as the case may be, not included. For the purpose of making TC calculations, I have relied on the costs presented by the Company in its exhibits and responses to information requests. The proper balances to actually be used in the calculation of the TC will be determined after the full independent audit.

III. <u>TRANSITION CHARGE</u>

A. <u>GENERAL</u>

1. <u>Basis of Termination Charge</u>

Q. What is the amount of the initial termination charge being proposed by WMECO?

A. WMECO is proposing an initial TC of $0.0318 for 1998.

Q. How did the Company calculate this transition charge?

A. This is the amount of the TC that, when combined with the other components of WMECO's unbundled rates, leads to an overall rate reduction of 10%. In this regard, it is a fixed amount that all the components of the TC must add up to.

Q. Has the Company also projected the transition charge beyond 1998?

A. Yes. Exhibit 13E, Schedule 1, page 1 also shows the projected transition charge by year for the years 1999 through 2010. In projecting the transition charge by year, the Company assumed that the non-nuclear plant would be divested (at book value) in 1999 and 2000, and the unrecovered nuclear plant costs and regulatory assets would be securitized in stages beginning January 1, 1999.

Q. In determining the transition charge, for the years 1999 through 2010, are you incorporating the effects of divestiture and securitization?

A. No. Consistent with the presentations of MECO and EECO, I have calculated the transition charge by year without reference to the effect of divestiture or securitization. WMECO characterizes its presentation as a calculation of the base transition charge. As the term has been used by MECO and EECO, the base transition charge does not include the effects of securitization or divestiture. To be consistent, and to maintain comparability, the calculation of the base transition for WMECO should not include the effect of securitization and divestiture. When divestiture does take place, and if securitization does take place, then the calculation of the transition charge should be modified to incorporate the effect of divestiture and securitization. Until these transactions actually occur, the effects of the divestiture and securitization are nothing more than assumptions that might, or might not, be borne out by reality.

In the response to Attorney General Information Request AG-19-12, the Company provided the path of the transition charge without the effect of divestiture or securitization. I have used the information provided in this response as the basis for my calculation of the transition charge by year. Again, this is consistent with the presentations of MECO and EECO.

Q. How have you determined the transition charge by year in your schedules?

A. For 1998 and 1999, I have held the transition charge at the $0.0318 per kwh proposed by WMECO. I have used the amortization expense as the residual to make the total of the items included in the TC equal to $0.0318 per kwh for those two years. For the years after 1999, I have amortized the fixed costs on the schedule proposed by WMECO and have calculated the transition charge as the sum of all the fixed and variable costs.

2. <u>Cost Allocation to WMECO Pursuant to NUG&T</u>

Q. Do the unrecovered plant balances on WMECO Exhibit 13E, Schedule 1, page 5 reflect the WMECO ownership shares of the plants indicated?

A. Yes. Thus, for example, the plant balances for the Millstone Units 1 and 2 reflect WMECO's 19% ownership share. For Millstone 3, the balance shown reflects the WMECO 12.2% ownership share, which is approximately 18.8% of the ownership of the parties to the NUG&T. The plant balance for Northfield Mountain reflects the WMECO 19% ownership share. With regard to the other hydro-electric units and fossil units, the plant balances shown reflect WMECO 100% ownership.

Q. Is the WMECO ownership share of the plants the same as WMECO's cost responsibility for ratemaking purposes?

A. No. The WMECO cost responsibility is based on the Northeast Utilities Generation and Transmission Agreement ("NUG&T"). The NUG&T allocates generation and transmission costs to its members, WMECO, Connecticut Light and Power ("CL&P"), and Holyoke Water Power ("HWP"), based on their contributions to load. Thus, all of the WMECO, CL&P, and HWP generation related costs, both capacity related and energy related, are included in the total pool of NUG&T generation costs. The capacity related generation costs are then allocated to each member based on its contribution to peak, and the energy related generation costs are allocated based on kwh sales. As WMECO's contribution to peak and relative kwh sales are different from its ownership share of the generating plants, its ultimate cost responsibility pursuant to the NUG&T is also different.

Q. Does WMECO's ownership share of the generating plants bear any relationship to its own load and generation mix needs?

A. No. The Department has already determined that WMECO ownership of the generating plants bears no relation to its own load and generation mix needs. The Department has also found that Northeast Utilities planned on a system basis and did not try to optimize each member company's generation mix because of the way that the NUG&T Agreement allocated costs. (Order, DPU 84-25, pages 46 - 47).

In addition, at the technical conference on March 26, 1998

John W. Noyes, speaking on behalf of WMECO, agreed that the NUG&T is, in substance, the same as if a single generating entity owned the facilities and recovered the costs by charging the distribution function (Technical Conference, March 26, 1998, Page 99). In fact, this is the equivalent of the corporate structure of New England Electric System and Eastern Utilities Associates. For those organizations, the generation costs were allocated to both MECO and EECO, respectively, based on their historic relative responsibilities for those costs. The allocation of generation costs to WMECO should also be based on its relative cost responsibility, pursuant to the NUG&T.

Q. If the cost of the generating units is included in the transition charge based on WMECO's ownership percentage, rather than WMECO's cost responsibility pursuant to the NUG&T, will this represent a shift of the cost responsibility for these units from what it has been under traditional ratemaking?

A. Yes. Basing the transition charge on WMECO's ownership share rather than its cost responsibility will result in a substantial cost shift to WMECO, mainly from CL&P. In particular, the transition charge will reflect a greater responsibility to WMECO for Millstone capacity related costs than WMECO has existed under traditional ratemaking.

Q. Should the determination of the plant balances to be recovered through the transition charge be modified?

A. Yes. The transition charge should reflect WMECO's cost responsibility for these generating plants pursuant to the NUG&T. Basing the recovery of the plant balances on WMECO's ownership share, rather than the NUG&T, would cause a cost shift that would impose a greater cost responsibility on WMECO ratepayers than they would be responsible for under a continuation of traditional cost based ratemaking. It is my understanding that the purpose of the transition charge is to permit WMECO to recover the costs that they might otherwise have been able to recover, if cost based ratemaking had continued in effect in Massachusetts. They should not be allowed to recover more than those costs.

Q. If the plant balances to be recovered through the transition charge are based on the NUG&T, rather than on WMECO's ownership share, should there also be other modifications to the transition charge formula?

A. Yes. The following components of the transition charge would also have to be modified to reflect WMECO's cost responsibility pursuant to the NUG&T, rather than WMECO's ownership share: the Millstone 1 regulatory asset (Exhibit 13E, Schedule 1, page 6(a), decommissioning costs (Exhibit 13E, Schedule 1, page 8), power contract obligations (Exhibit 13E, Schedule 1, page 9), nuclear PBR (including the treatment of unavoidable nuclear costs), and the deferred taxes related to the fixed component (Exhibit 13E, Schedule 1, page 11). In addition, the calculation of the residual value credit would have to be modified to reflect WMECO's cost responsibility. This would entail attributing a portion of the value of WMECO's owned generating stations to the other NUG&T

members based on traditional cost responsibility and attributing a portion of the value of the other NUG&T members' generating stations to WMECO, including a portion of the value of units such as HWP’s Mt. Tom coal plant, again based on the historic cost responsibility for these generating stations.

Q. Have you prepared a schedule which shows how the cost responsibility pursuant to the NUG&T agreement would be incorporated into the WMECO transition charge.

A. Yes. I have prepared my Schedule 1A, which calculates the transition charge based on the WMECO cost responsibility pursuant to the NUG&T, rather than on WMECO's ownership share. This, in general, results in a reduction to the WMECO TC. For, example, as can be seen by comparing the TC rates on Schedule 1A, Page 1 to Schedule 1B, Page 1, in 2000 the TC on a WMECO "stand alone" basis is $0.02844 while the TC based on the WMECO NUG&T cost responsibility is $0.02598.

Q. How did you calculate the traditional responsibility for generation related costs pursuant to the NUG&T?

A. I based the traditional cost responsibility for WMECO on WMECO's weighted average share of the NUG&T capacity costs and energy costs for the years 1993 - 1997. The supporting calculations are shown on Schedule 1A, Page 9. This is generally consistent with the method used by NEES and EUA to allocate generation costs among its distribution subsidiaries for the purpose of calculating the transition charges in Massachusetts and Rhode Island.

Q. Was it necessary to make other assumptions in calculating the impact of reflecting the NUG&T?

A. Yes. This exhibit necessarily required certain assumptions in incorporating the effect of the NUG&T. Where applicable, these assumptions are shown the pages of Schedule 1A. Because the incorporation of the NUG&T changes the whole basis for the determination of the transition charge, I have reflected this as a separate schedule. In Schedule 1B, I show the effect of incorporating the other modifications that I am proposing, exclusive of the effect of basing the cost recovery on the NUG&T.

B. <u>FIXED COST COMPONENT OF TC</u>

1. <u>Recovery of Millstone Costs</u>

Q. Have you incorporated the AG's position on the recoverability of Millstone costs in your calculation of the TC?

A. Not at this time. However, when the AG testimony on nuclear issues is filed, I will modify my calculation of the TC to reflect the proposed recovery of Millstone costs.

2. <u>Regulatory Assets</u>

a. Deferred Fuel

Q. Has the Company proposed to include deferred fuel costs in the regulatory assets recovered through the transition charge?

A. Yes. The Company has included a deferred fuel balance of $23,100,000 in regulatory assets as of March 1, 1998. The Company is proposing to amortize this balance over twelve years and include the unamortized balance in the regulatory assets earning a return. As explained by the Company, this balance reflects the estimate of unrecovered costs associated with the operation of WMECO's fuel clause.

Q. Should the deferred fuel balance be included in regulatory assets recovered through the transition charge?

A. No. It is my understanding that the Department has opened a generic docket to address the ratemaking treatment of the final balance of fuel clause costs that are over or under recovered as of the retail access date. In the generic docket, the Department will be able to review the calculation of the deferred fuel balances, the extent to which there should be carrying costs on the deferred fuel balances, and the appropriate carrying cost rate to be used. For example, it is my understanding that as a result of prior settlements, there should be no return on a portion of the deferred fuel balance recorded by WMECO. It cannot be determined from the information provided by WMECO whether the deferred fuel balance included in the regulatory assets earning a return has been properly adjusted to exclude the deferred fuel balance which should not be earning a return. In addition, it is my understanding that there are also prudence issues regarding the recoverable balance of deferred fuel. Given the areas already at issue in the determination of the transition charge, I believe that it would be unduly burdensome to attempt to address all fuel recovery issues in the context of this proceeding. The Department will be able to appropriately address issues such as this and other fuel recovery issues in its separate generic docket or in a generating unit performance review.

Q. Have you eliminated the deferred fuel from the calculation of the transition charge?

A. Yes. On my Page 5, I have eliminated the deferred fuel balance from the regulatory assets to be recovered through the TC. There should be no deferred fuel balance in the regulatory assets earning a return, and there should be no amortization of deferred fuel included in the computation of the transition charge.

b. Deferred Nuclear Outage

Q. Has the Company included deferred nuclear outage costs in regulatory assets?

A. Yes. The Company has included a return on and a return of deferred nuclear outage costs in its calculation of the TC.

Q. Is this treatment appropriate?

A. No. In response to Attorney General Information Request 3-10, the Company stated that it has not been the practice of the Department to include deferred nuclear outage expense in rate base for the purpose of determining retail revenue requirements. If the Company is allowed to include a return on the deferred nuclear outages in the calculation of the transition charge, it would be, in effect, recovering through the transition charge what it could not recover under traditional ratemaking.

The purpose of the transition charge should be to allow the Company to recover what it could recover if traditional ratemaking had continued. However, the transition charge should not be used as a mechanism to allow the Company to recover what it could not recover as a component of its cost of service for ratemaking purposes under traditional ratemaking. Accordingly, the treatment of the deferred nuclear outage costs in the calculation of the TC should be modified.

Q. What do you recommend?

A. If there is to be any recovery of the deferred nuclear outage costs, then I recommend that the deferred nuclear outage costs be treated as a regulatory asset not earning a return for the purpose of calculating WMECO's transition charge. This would preserve the treatment of this cost under traditional ratemaking. For the purpose of calculating the TC as part of this testimony, I have removed the deferred nuclear outage cost from the regulatory assets earning a return and for now included this balance in the regulatory assets not earning a return. In the nuclear issues phase of this proceeding, the question of whether there should be a return of, as opposed to a return on, these deferred costs will be addressed.

c. Excess Pension Funding

Q. What is the market value of the assets in the Company's pension fund compared to the projected benefit obligation?

A. According to the footnotes to the 1997 WMECO Annual Report, as of December 31, 1997, the market value of Company's pension plan assets was $181,028,000, compared to a projected benefit obligation ("PBO") of $109,536,000. Thus, the market value was $71,492,000 in excess of the PBO.

Q. In calculating the TC, did WMECO recognize the excess of the market value of the pension plan assets over the PBO?

A. No. Although the Company is proposing to include the FAS 106 transition obligation in the calculation of the TC, it is not proposing any parallel recognition of the market value of its pension funds in excess of the PBO.

Q. What is the Company's stated reason for ignoring the overfunding of its pension obligation in the determination of the transition charge?

A. In response to Attorney General Information Request 3-17, the Company stated that it is legally prohibited from using the value of the pension plan assets in excess of the pension benefit obligation as an offset to the regulatory assets included in the transition charge.

Q. Is this explanation plausible?

A. No. In response to Attorney General Information Request 14-14, the Company was unable to cite any cases supporting its contention that regulators are legally prohibited from giving recognition to pension plan assets in excess of the projected benefit obligation in determining the appropriate computation of a competitive transition charge.

In addition, MECO, EECO and BECO agreed to include the excess of the value of pension plan assets over the pension benefit obligation in their transition charge calculations. Although the treatment agreed to by MECO, EECO, and BECO were in the context of settlements, and as such are not legal precedent, I do not believe that the signatories to those settlements would have voluntarily agreed to anything that would have violated any applicable law. That is, if there was a legal prohibition to recognizing the pension overfunding in the determination of the transition charge, I do not believe that the representatives of these companies would have agreed to the treatment that they did.

Q. If the excess value of pension assets over the pension benefit obligation is included in the determination of the transition charge, does this imply that WMECO would have to raid its pension fund for the benefit of customers?

A. Absolutely not. This would simply be an accounting recognition of the overfunding of WMECO's pension plans at the time of the restructuring. The ratepayers have paid for this overfunding, and the amount of the overfunding that relates to the generation function should be recognized in the determination of the transition charge.

Q. What would happen if there is no recognition of the pension overfunding in the calculation of the transition charge?

A. There will be an unreasonable windfall to WMECO and its investors. That is, if traditional cost of service rate regulation were to continue for the generation function, the benefit of the pension overfunding would implicitly be passed along to ratepayers. However, with the generation function being deregulated, there is no vehicle to pass this benefit to ratepayers in the future. With the price of generation based on market, rather than cost, the benefit of the pension overfunding would inure to WMECO and its investors, even though ratepayers had paid for this overfunding.

Again, if the purpose of the transition charge is to allow the Company to recover what it would be able to recover under traditional ratemaking, then there must be some offset to the regulatory assets included in the transition charge for pension overfunding. In effect, the excess of pension fund assets over the pension benefit obligation is a regulatory liability that the Company owes to its ratepayers.

Q. Should the Company include the market value of its pension fund assets in excess of the PBO in the calculation of the TC?

A. Yes. The Company is proposing to include the transition obligation related to post retirement benefits other than pensions (FAS 106) in the calculation of the TC. To be consistent, there should also be a recognition of the market value of pension fund assets in excess of the PBO, which is calculated pursuant to FAS 87, in the calculation of the TC, to the extent that the excess of the market value over the PBO is generation related.

Further, the TC allows the Company to collect the cost in excess of market value of its generating plants and purchased power contracts. To be consistent, the value of the pension funds in excess of the cost of the pension benefit obligation should also be reflected in the determination of the TC.

Q. Have you calculated the amount of the market value in excess of the PBO that should be included in the calculation of the TC?

A. Yes. On Schedule 1B, Page 5a, I have calculated the generation related market value of pension assets in excess of the PBO that is related to the generation function. I have allocated the pension assets in excess of the PBO to generation using the same allocation method that the Company used for FAS 106, including allocation of the pension assets in excess of the PBO for Northeast Nuclear Energy Company and Northeast Utilities Service Company.

In my calculation, I have recognized the excess value only to the extent that it exceeds 5% of the value of the pension funds, consistent with the "corridor" method of recognizing the difference between the market value of the pension funds and the PBO. (That is, the difference between the market value of the pension fund and the PBO is recognized only to the extent that it is more than 5% of the market value or the PBO, whichever is greater.) I have also offset the excess market value by the prepaid pension asset on the Company's books, in that the prepaid pension asset represents pension costs recognized by the Company that have not be recovered through rates. As can be seen on Schedule 1B, Page 5a, the unrecognized pension gain applicable to WMECO is $23,393,000. Finally, I have included an amortization of the excess pension funding over twelve years, as a credit to the amortization of regulatory assets. Again, this is consistent with the Company's treatment of FAS 106.

Q. Should there be a future true-up of the difference between the market value and the PBO?

A. Yes. The Company should reconcile the estimated balance for the excess pension funding being included in the TC at this time with the actual excess pension funding at the date of divestiture, to the extent that the pension obligation is associated with the plant being divested, and include the difference in the reconciliation account, as the Company is doing with regard to FAS 106.

Q. Is the treatment that you are proposing for the excess pension funding consistent with the treatment used by MECO, EECO and BECO in their calculations of their transition charges?

A. Yes. The transition charge formulae for MECO, EECO, and BECO treat FAS 106 and FAS 87 in a parallel manner, as I have proposed here.

d. Return on FAS 106 and FAS 87 Balances

Q. In determining the transition charge, has WMECO included a return on the FAS 106 balance?

A. Not explicitly. However, the FAS 106 balance included in regulatory assets includes the effect of a return component on a present value basis, and the FAS 106 balance is then treated as a regulatory asset not earning a return. Because the Company did not treat the FAS 87 excess pension funding as a regulatory liability, there was obviously also no recognition of any return related to FAS 87.

Q. Should the calculation of the TC include a recognition of the return on the FAS 106 and FAS 87 balances?

A. Yes. However, the rate of return that is applied to these balances should not be the same rate of return that is applied to the net plant balances and other regulatory assets.

Q. What rate of return should be applied to the FAS 106 and FAS 87 balances?

A. The discount rate used in the actuarial determination of the present value of the benefit obligation should be used as the rate of return. In 1997, WMECO used a discount rate of 7.75% to calculate both the pension cost and other postretirement benefit cost. This is the rate of return that I have used for the purpose of calculating the return component related to the FAS 106 regulatory asset and the FAS 87 regulatory liability.

Q. Why is this the appropriate rate to use?

A. The FAS 106 regulatory asset and FAS 87 regulatory liability are not included in the Company's determination of rate base for revenue requirement purposes. However, these items represent the discounted present value of future obligations. The obligation (which in the case of pensions is a negative obligation, or unrecognized asset) will accrete annually by the amount of the discount rate. The effect of this annual accretion should be recognized by application of the discount rate to the regulatory asset or liability in the TC calculation for the purpose of calculating carrying charges.

On Page 5, I have calculated a return on the FAS 106 and FAS 87 balances by applying the discount rate used by the Company in its actuarial studies. As I am separately providing for a return, I have included the FAS 106 transition obligation in regulatory assets without any implicit return component.

e. FAS 109

Q. Has the Company included its FAS 109 regulatory asset in the calculation of the TC?

A. Yes. The Company has included the FAS 109 regulatory asset, which is the offset to the additional accumulated deferred income taxes calculated pursuant to FAS 109, in the determination of its TC.

Q. What does the FAS 109 regulatory asset represent?

A. Pursuant to Statement of Financial Accounting Standards 109, the Company must record accumulated deferred income taxes on all temporary book-tax differences. The net accumulated deferred income tax liability otherwise recorded on the Company's books and recognized for ratemaking purposes is less than the amount that would be recorded pursuant to FAS 109. Thus, the Company must book an entry to recognize the additional liability pursuant to FAS 109. Because this amount will ultimately be recovered through the ratemaking process, an offset to the additional FAS 109 liability is recorded as a regulatory asset. It is the generation related portion of this FAS 109 regulatory asset that is included in the TC.

Q. Should any aspect of the Company's treatment of the FAS 109 regulatory asset be modified?

A. Yes. The Company’s treatment does not properly recognize the relationship between the calculation of the FAS 109 regulatory asset and the calculation of accumulated deferred income taxes. As explained above, the FAS 109 regulatory asset is an offset to the entry to deferred taxes necessary to recognize normalization of all temporary book-tax timing differences. The establishment of this regulatory asset did not entail any cash outlay. If the FAS 109 regulatory asset is included in the TC, then deferred taxes should be calculated on a basis consistent with the development of that regulatory asset, and should reflect the normalization of all book-tax timing differences.

The Company has excluded the FAS 109 regulatory asset balance from the net regulatory assets earning a return. The FAS 109 regulatory asset should be included in the balance of regulatory assets earning a return. Then, consistent with this treatment, the deferred tax offset used in calculating the carrying charge element of the TC should be determined by applying the income tax rate to the difference between the full book basis of plant balances and regulatory assets and the tax basis of those plant balances and regulatory assets. This treatment of the FAS 109 regulatory assets and calculation of the accumulated deferred income taxes is internally consistent with the development of the

FAS 109 regulatory asset and its recognition as a component of the TC. It is also consistent with the method used by MECO and EECO in their calculations of the transition charge.

f. Prior Spent Nuclear Fuel

Q. Has the Company recognized a regulatory liability for prior spent nuclear fuel in the calculation of the TC?

A. Yes. The accrual for the prior spent nuclear fuel balance is a regulatory liability that the Company deducts from the regulatory assets in the calculation of the TC. The prior spent nuclear fuel balance reflects the amount that has been recovered through rates for spent nuclear fuel but which has not been paid to the Department of Energy. This liability accrues interest at the three month U.S. Treasury Bill rate.

Q. Should the interest on this liability be included in the calculation of the TC?

A. Yes. Consistent with the treatment of the prior spent nuclear fuel balance as a regulatory liability that is deducted from regulatory assets, the interest associated with this liability should be included in the determination of the transition charge. This is equivalent to treating interest on customer deposits as an operating expense when customer deposits are deducted from rate base in a traditional utility revenue requirement case.

The Company has treated the interest on the prior spent nuclear fuel balance as a component of the "unavoidable" nuclear costs reflected in the TC. However, because this expense relates directly to the regulatory liability, the interest should be separately identified and included in the determination of the TC. The treatment of this interest expense should not depend on the ultimate treatment of the unavoidable nuclear costs or the nuclear PBR, in the event that Department adopts a treatment of the going forward nuclear costs different from that proposed by the Company. Accordingly, I have reflected the interest on the prior spent nuclear fuel balance as a separate element of the variable component of the TC on Page 3.

3. <u>Standard Offer Deferral</u>

Q. Has the Company included its projection of standard offer deferrals in the transition charge?

A. Yes. The standard offer deferrals are summarized on Exhibit 13E, Schedule 1, page 2A. These deferrals total more than $100 million for the years 1998-2004. The deferrals represent the difference between the forecasted retail market value of power and the retail standard offer price for each of the years indicated. WMECO is proposing to defer this difference, securitize the deferred costs, and include the payments on the securitized balances in the TC.

Q. Should these standard offer deferrals be included in the calculation of the TC?

A. No. To the extent that WMECO loses revenue as a result of having to provide standard offer service at a price less than the prudent cost of service for its generation, that should be included in its lost revenue calculation that is used to adjust the residual value credit.

Q. Is there a difference between the wholesale price of standard offer service and the retail price of standard offer service?

A. Yes. There is such a difference for the years 1998 - 2000. The difference for those years is as follows:

	Wholesale	Retail
1998	$0.032	$0.028
1999	$0.035	$0.031
2000	$0.038	$0.034

Q. Should the Company be able to defer this difference for subsequent collection?

A. This would be consistent with the treatment approved by the Department for other companies.

C. Return on Unamortized Fixed Costs

Q. Does the Company's transition charge include a return component?

A. Yes. The return component is shown on Schedule 1, Page 12 of Exhibit 13E. It is calculated by applying the rate of return to the unamortized balance of the fixed component of the transition charge.

Q. How did the Company calculate the rate of return to be applied to the unamortized balance of the fixed component?

A. The Company calculated the rate of return based on its 1995 capital structure and the 1995 cost rates for long term debt and preferred stock. The return on common equity included in the overall weighted average rate of return is 11.0%, and the weighted costs of preferred stock and common equity are grossed up for applicable income taxes. The pre-tax weighted average rate of return used to calculate the return component included in the TC is 12.64%.

Q. Should the Company's calculation of the rate of return be modified?

A. Yes. As I discuss below, the capital structure, cost rate of long term debt, and cost rate of preferred stock should be updated. Furthermore, I recommend that the return on common equity be determined on the same basis as it was in the MECO, EECO and BECO settlements.

1. Capital Structure

Q. What capital structure did the Company use for the purpose of calculating the overall rate of return?

A. The Company used the 1995 average year end capital structure.

Q. Is this the proper capital structure to use for the purpose of determining the weighted average rate of return to be used in calculating the return component of the transition charge?

A. No. The transition charge commenced in March, 1998. The capital structure as of 1995 is not pertinent to determining the rate of return in March, 1998. I seriously doubt that in the context of determining revenue requirements in a traditional rate case the Department would use a capital structure over two years old for the purpose of calculating the rate of return. Similarly, for the purpose of determining the return component to include in the transition charge, the capital structure should be updated to reflect the capital structure ratios as of the implementation of the TC.

Q. What do you recommend?

A. I recommend that the capital structure used in calculating the rate of return be updated to reflect the balances of the first quarter of 1998. On Page 7, I show the ratios of long term debt, preferred stock, and common equity as of the end of 1997, as an estimate of the ratios for first quarter of 1998. I used these year end 1997 balances as estimates because the Company declined to provide the ratios as of March 1, 1998, despite being requested to do so several times.

2. <u>Cost Rate of Long Term Debt</u>

Q. What cost rate for long term debt has the Company incorporated into its determination of the overall rate of return?

A. The Company has used a cost rate of 7.81% for long term debt. Again, this is based on the 1995 cost of long term debt.

Q. Should the cost rate used in the determination of the rate of return be modified?

A. Yes. Again, the cost rate of long term debt should be updated to reflect the rate at the time of the implementation of the transition charge. The 1995 cost rate of long term debt is not relevant to the determination of a charge commencing in 1998. The cost rate of long term debt as of March 1, 1998 is 7.60%, and this is the rate that I have used in the calculation of the overall rate of return.

3. Cost of Preferred Stock

Q. What cost rate for preferred stock has the Company incorporated into its determination of the overall rate of return?

A. The Company has used a cost rate of 7.13% for preferred stock. Again, this is based on the 1995 cost of preferred stock.

Q. Should the cost rate used in the determination of the rate of return be modified?

A. Yes. Again, the cost rate of preferred stock should be updated to reflect the rate at the time of the implementation of the transition charge. The 1995 cost rate of preferred stock is not relevant to the determination of a charge commencing in 1998. The cost rate of preferred stock as of year end 1997 (again used as an estimate because the Company did not provide the actual rate as of March 1, 1998) was 8.74%, and this is the rate that I have used in the calculation of the overall rate of return.

4. Return on Common Equity

Q. What return on common equity does the Company include in the calculation of the overall rate of return?

A. The Company includes a return on common equity of 11.00%.

Q. What is the basis of the 11.00% return on common equity included by the Company in the determination of the overall rate of return?

A. As far as I know, the Company has provided no basis for why this is the appropriate return on common equity to be used in determining the overall rate of return. In fact, the 11.00% return on common equity appears for the first time in Company Exhibit 13E and is a departure from the return on equity used in all prior versions of Exhibit 13, dating back to January, 1998. In all prior versions, the return on equity was less than 11.00%.

Q. Do you believe that 11.00% is a reasonable return on common equity to use in calculating the return component of the TC?

A. No. I recommend that the Department determine the cost of equity component of any carrying costs included in the transition charge based on the formula used to determine the transition charges of MECO, EECO, and BECO. That formula bases the return on equity on the level of the transition charge. Pursuant to this formula, as the cumulative average of the transition charge decreases, the allowed return on equity increases. With a transition charge of $0.0318, which is the Company's calculated transition charge for 1998, application of the appropriate formula results in a return on equity of 8.64%. This is the return on common equity that should be used in calculating the rate of return. As I explain later in my testimony, use of this formula provides the Company with proper incentives to mitigate the TC. On Schedule 4, I show a table that summarizes the allowable return on equity for different transition charges based on this formula.

5. Income Tax Rate

Q. What income tax rate does the Company state should be used for the purpose of grossing up the preferred stock and common equity components of the rate of return?

A. On Page 6 of the text accompanying Exhibit 13E, the Company describes a combined state and federal income tax rate of 40.6059% as the combined tax rate "currently in effect". However, it is not.

In response to Attorney General Information Request 8-15, the Company explained that the 40.6059% effective income tax rate includes consideration of "excess deferred taxes". To the extent that excess deferred taxes exist, it would impact the balance of accumulated deferred income taxes deducted from unamortized fixed costs in calculating the balance to which the rate of return is applied. However, the income tax rate used to gross up the preferred stock and equity components of the rate of return should be based on the current income tax rate, as the return component is prospective and is not affected by the existence of excess accumulated deferred taxes.

Q. What income tax rate should be used to gross up the preferred stock and equity components?

A. As stated by the Company in its response to Attorney General Information Request 19-2, the current combined effective income tax rate is 39.225%. In fact the Company itself implicitly uses this combined tax rate on Exhibit 13E, Schedule 1, Page 12. Accordingly, on Page 8, I also use a combined state and federal income tax rate of 39.225% for the purpose of determining the pre-tax rate of return.

6. Accumulated Deferred Taxes

Q. Should there be any other adjustments to the calculation of the return component of the transition charge?

A. Yes. As I have explained above, the calculation of the accumulated deferred income taxes deducted from the unamortized fixed costs in calculating the base to which the rate of return is applied should be modified. The FAS 109 regulatory asset includes the effect of timing differences which had not been normalized, including prior flow through of accelerated depreciation and the equity component of AFUDC. It is the offset to the adjustment to the book balance of accumulated deferred income taxes that would be necessary to recognize full normalization of all timing differences. In this regard, it also implicitly recognizes the effect of any excess accumulated deferred income taxes resulting from the use of higher income tax rates in prior years.

With the FAS 109 regulatory asset included in the total of regulatory assets earning a return, the accumulated deferred income taxes that offset the balance of unamortized fixed costs can be calculated by simply applying the current combined income tax rate to the difference between the book basis of the fixed component earning a return and the tax basis of all items included in the balance earning a return. On Page 5, I have included the net FAS 109 regulatory asset in the balance of regulatory assets earning a return. Accordingly, on Page 8, I have calculated the accumulated deferred tax offset to the balance of the fixed component earning a return by applying the combined state and federal income tax rate to the difference between the book basis and tax basis of those items.

Again, this is the appropriate and internally consistent method of recognizing the FAS 109 regulatory asset in the transition charge and calculating the deferred tax offset to the fixed component for the purpose of calculating the return component of the TC.

D. <u>VARIABLE COSTS IN TC</u>

1. <u>Generation Operating Costs</u>

Q. Has the Company included an item which it has labeled "Generation Operating Costs" in the variable component of the transition charge?

A. Yes. Exhibit 13E, Schedule 1, Page 3, includes $11,070,000 of "Generation Operating Costs" in the variable component of the transition charge.

Q. What do these Generation Operating Costs represent?

A. As explained by the Company, the Generation Operating Costs are included to reflect the support of continued operation of the NUG&T agreement.

Q. How are the Generation Operating Costs calculated?

A. The calculation of the Generation Operating Costs is shown on Exhibit 13E, Schedule 1, page 3A. As represented on this page, the Generation Operating Costs are the difference between the NUG&T costs included in the total cost of service and the elements of the NUG&T that are included in the transition charge (exclusive of the Millstone replacement power), less revenues from sales at the standard offer rate.

Q. Is it necessary to include the Generation Operating Costs in the variable component of the transition charge?

A. No. Section B.1.1.3 (b) (ii) of the text accompanying Exhibit 13E states that the residual value credit will be adjusted by "any revenues lost by WMECO between the retail access date and the divestiture date, measured by the difference between the unit's revenues that WMECO would have collected from the fully allocated (e.g., including A&G) generation portion of the most recently Department approved rates and unit's market revenues plus any transition charge revenues related to the unit sold."

This is exactly the same formula that is used to calculate the Generation Operating Costs on Exhibit 13E, Schedule 1, page 3A. The revenues lost by WMECO are based on the generation cost of service, which is the same as the "Cost of Service Total" column on Exhibit 13E, Schedule 1, page 38. Thus, to include the Generation Operating Costs in the variable component of the transition charge and to also include a lost revenue offset to the residual value credit would constitute a double count.

Accordingly, the Generation Operating Costs should be removed from the variable component of the TC.

Q. Do the MECO or EECO transition charges include anything analogous to the Generation Operating Costs in the variable components of their transition charges?

A. No, they do not. The formula for the MECO and EECO transition charges include an offset to the residual value credit that is substantially the same as the lost revenue definition contained in the WMECO transition charge formula. However, there is no additional component of the MECO and EECO transition charges for ongoing Generation Operating Costs incurred prior to the divestiture. The transition formulae for MECO and EECO contain no such double counting, and neither should the formula for WMECO.

2. <u>Unavoidable Nuclear Costs</u>

Q. Has WMECO included "unavoidable nuclear costs" in the variable component of the transition charge?

A. Yes. The "unavoidable nuclear costs" for the years 1999 through 2003 are shown in column M of Exhibit 13E, Schedule 1, Page 3.

Q. What do these "unavoidable nuclear costs" represent?

A. The "unavoidable nuclear costs" represent the costs associated with the ownership of nuclear power plants that WMECO asserts cannot be avoided, even if the plants are not running. These costs include insurance, security, property tax, NRC fees, "regulatory compliance", and interest on spent nuclear fuel. The

Company includes the "unavoidable nuclear costs" in the transition charge from the time of the divestiture of the non-nuclear facilities to the divestiture of the nuclear facilities, which is assumed to be January 1, 2004. It should be noted that although these costs do not vary with the operation of the units, they are not necessarily constant over time and can change from year to year.

Q. Is this the appropriate treatment for the "unavoidable nuclear costs"?

A. No. First, as I have explained in my testimony on regulatory assets, the interest on the spent nuclear fuel should be treated as a separate item in the variable component of the transition charges.

Second, the treatment of the other "unavoidable nuclear costs" should be the same as the treatment of the other nuclear operating expenses in the PBR for nuclear units. Thus, there should not be a separate item for "unavoidable nuclear costs" in the variable component of the transition charge. Rather, the "unavoidable nuclear costs" should be included in the nuclear PBR formula. I will explain this in my testimony on the nuclear PBR in the nuclear issues phase of this proceeding.

3. Claims Net of Recoveries

Q. Does the variable component of the transition charge include an item for damages, costs, or net recoveries from claims?

A. Yes. This is shown in column K in Exhibit 13E, Schedule 1, page 3. For the purpose of Exhibit 13E, this item is assumed to be zero.

Q. Should the definition of this item be modified?

A. Yes. Section B.1.2.3 (h) of the transition charge formula specifies that this item relates to "damages, costs, or recoveries associated with the generating business of WMECO, or its affiliates, which accrued prior to the date of divestiture and which were not recovered from their insurance carriers." To the extent that WMECO has already accrued a reserve for future damages, any prudent expenditures for damages should be charged against the reserve rather than to the transition charge. If charges for damages that accrued prior to the date of divestiture exceed the reserve for such damages, then the charges should be eligible for inclusion in the transition charge, subject to audit of the balances and the prudence of any expenditures.

E. <u>POTENTIAL SUBSEQUENT ADJUSTMENTS TO TC</u>

1. <u>Lost Revenue</u>

Q. Does the WMECO transition charge formula include a provision to recover lost revenue from the time of the retail access to the divestiture?

A. Yes. The transition charge formula provides for an offset to the residual value credit for revenues lost by WMECO between the retail access date and divestiture date as measured by the difference between the revenues WMECO would have collected based on fully allocated generation costs and the market value of such revenues plus transition charge revenues.

Q. Should the formula for lost revenue be modified?

A. Yes. The lost revenue formula for MECO, EECO, and BECO all include a cap of 8 mills per kwh. The formula for lost revenue includable in the TC for WMECO should be modified so that it is also capped at 8 mills per kwh. In that it is my understanding that the Act does not explicitly provided for any recovery for such lost revenue, it is not unreasonable to cap the recovery at 8 mills per kwh.

2. <u>True-Up for Lost ROE</u>

Q. Does WMECO's transition charge formula include a true-up for lost return on equity?

A. Yes. The Company is requesting to defer, and subsequently collect, costs that will restore an 11% return on equity, to the extent that such return is foregone in 1998 as a result of the rate cap.

Q. Should the Company's proposal to true up the 1998 return on equity to 11% be included in the transition charge formula?

A. No. Again, there is an appropriate formula to calculate the return on equity component of any carrying costs included in the TC, and it does not entail any automatic true-up to an 11.00% return on equity. As I explain later in my testimony, the return on equity component of the TC should be based on the level of the

TC, to provide a proper incentive to mitigate the costs that go into the TC.

3. <u>True-Up to FAS 106, FAS 87</u>

Q. Does the Company's proposed transition charge formula include a true-up related to the accumulated post-retirement benefit obligation associated with the FAS 106 transition obligation?

A. Yes. Section B.1.1.3(a)(i) provides for a true-up to the actual balance at the date of divestiture for the accumulated post-retirement benefit obligation associated with the FAS transition obligation.

Q. Should the definition of this adjustment be modified?

A. Yes. The definition should be modified to specify that the true-up will include the effect of any actuarial gains or losses associated with the accumulated post-retirement benefit obligation, as of the time of each divestiture. The FAS transition obligation was originally calculated at the time of the adoption of FAS 106 for financial reporting purposes. Since that time there have been changes in actuarial assumptions related to cost escalation rates, discount rates, return rates, and other actuarial inputs to the determination of the FAS 106 benefit obligation. The true-up to the FAS 106 transition obligation should also include the effect of the actuarial gains or losses on the FAS 106 post-retirement benefit obligation. Again, this would be consistent with the transition charge formulae for MECO and EECO.

Q. Should there be any other adjustment to the fixed component of the transition charge?

A. Yes. I am recommending that the difference between the market value of pension fund assets and the projected benefit obligation be reflected into the determination of the transition charge, to the extent that this difference exceeds 5% of the market value of the plan assets. This balance should also be adjusted to reflect its status at the time of divestiture. Again, this is consistent with the provisions of the MECO and EECO transition charge formulae.

F. <u>OTHER ISSUES AFFECTING THE TC</u>

1. <u>Projected Rate Path</u>

Q. Has the Company presented any analysis showing how its projected rates through the year 2004, the end of the standard offer transition period, compare to its present rates (after reflecting the 10% rate reduction mandated by the Act) adjusted for inflation?

A. No. In Attorney General Information Request AG-18-16, the Company was asked to provide calculations showing how its proposed rates through 2004 for customers taking standard offer service comply with the inflation cap in the Act. Rather than presenting any such analysis, the Company simply stated that it is "fully aware that an inflation cap applies" and that it "will, in accordance with the law, keep these rates under the inflation cap". However, the Company has provided no specifics of how it expects to attain this goal.

Q. Have you prepared an analysis of how the projected rate path compares to the capped rates adjusted for inflation?

A. Yes. On Schedule 2, I have presented a comparison of the path of WMECO's rates through 2004 to the present total rate adjusted for inflation. For the purpose of this comparison, I have adopted the following assumptions:

1. An inflation rate of 2.0% per year.
2. No change to the distribution or transmission rates from the rates shown in Company Exhibit 7, for the years 1998 - 2004.
3. The retail standard offer service rate by year as specified on Exhibit 13E, Schedule 1, Page 2A.
4. The transition charge as specified in Exhibit 13E, Schedule 1, Page 1, which itself assumes successful securitization and divestiture of non-nuclear generation assets at book value.

As can be seen on this Schedule, the Company's total average rate for years 2000, and each year thereafter, exceeds the inflation cap. Again, it should be noted that for the purpose of this analysis, I have not modified the Company's assumptions with regard to divestiture and securitization. If, for example, the effect of securitization were eliminated, the transition charges would be significantly higher for the years 1999 - 2004.

Q. Do you believe that, to the extent your analysis required assumptions beyond the assumptions used by WMECO in its TC calculations, your own assumptions are reasonable?

A. Yes. The rates for standard service and the transition charges are taken directly from the Company's presentation. With regard to the distribution and transmission rates, I believe that assuming no change in these rates for the years 1998 - 2004 is reasonably conservative.

With regard to the inflation rate, the 2.0% assumption, is also reasonably conservative. If I had assumed a higher inflation rate, then at some point, the total average rate would comply with the inflation cap. However, the higher the inflation rate, the less realistic the assumption regarding no change in the transmission rates or distribution rates becomes.

Q. What do you conclude from this analysis?

A. As presented, it is highly unlikely that the total average rates charged by WMECO for the years 1998 - 2004 would comply with the inflation cap. The department should require the Company to present some description of the steps that it plans to take to ensure that the rates being charged during the standard offer transition period will comply with the inflation cap specified in the Act. A statement that the Company is aware of the inflation cap and tends to keep its rates under the inflation cap is not adequate. The Company should be required to provide specifics of how this will be accomplished.

2. <u>Securitization</u>

Q. Have you reviewed the Company's plans to securitize certain costs included in the transition charge?

A. Yes. The Company has assumed that it will securitize nuclear plant costs and regulatory assets and has reflected the results of the assumed securitization transactions in the calculation of the TC. The initial securitization of $496,455,000 is assumed to take place January 1, 1999. The securities are assumed to carry a 6.25% interest rate for 12 years, with equalized annual payments of interest and principal over the 12 year term. Smaller securitizations are expected to take place each year 2000 through 2004. On Schedule 3, I summarize the securitizations assumed to take place in each of these years and the annual payments resulting from each of these securitizations. The total securitization payments by year for the years 1999 - 2010 are shown on Company Exhibit 13E, Schedule 1, page 2 under the column headed "Interest Mortgage Payment".

Q. Would these interest mortgage payments continue beyond the year 2010?

A. Yes. Each of the securitization transactions is assumed to have a 6.25% interest rate and a 12 year term, as shown in the response to AG 14-3. Thus, the payments on the securitization taking place January 1, 2000 would not be complete until December, 2011. Similarly, the securitization transaction taking place January 1, 2004 would not be complete until December, 2015.

Based on its response to Attorney General Information Request AG-19-5, the Company seems to believe that there will be no interest mortgage payments after the year 2010. There will be no interest mortgage payments associated with the initial securitization taking place January 1, 1999 after the year 2010. However, if the subsequent securitization transactions also have a twelve year term, there will be interest mortgage payments associated with those securitizations subsequent to 2010.

On Schedule 3, I show the amount of the interest mortgage payments for each year 1999 - 2015. It can be seen that for the years 1999 - 2010, the interest mortgage payments are exactly the same as shown by the Company on Exhibit 13E, Schedule 1, page 2, Column D. Given the assumptions used by the Company in calculating the interest mortgage payments for the years 1999 - 2010, there must also be interest mortgage payments for the years 2011 - 2015, as shown on this schedule.

Q. Does the Company's calculation of transition charges include an allowance for carrying costs for any period beyond the year 2009 on the unamortized balance of costs allowable as transition costs?

A. Yes. The last interest mortgage payment in the Company's presentation of the transition charges takes place in 2010. This would include interest on the unamortized principal of the securitized balance of the transition charge. Similarly, the securitization payments beyond the year 2010 also include interest on the unamortized principle balances.

It is my understanding that the inclusion of interest on the unamortized securitization principal in 2010 in the transition charge is inconsistent with the provisions of the Act specifying that no carrying costs will be allowed for the period beyond 2009 on any unamortized balance of costs allowable as transition costs (Section 1G(b)(3)(d)). The Company has not stated whether it plans to continue fixed cost recovery in the transition charge beyond the year 2010, and, if so, it intends to include the interest on the unamortized principle balances associated with the securitization. However, if the Company does intend to recover this interest beyond the year 2010, then it is my understanding that this too would be inconsistent with the Act.

Q. What would happen if the interest mortgage payments related to this securitization were not extended beyond 2009?

A. Assuming that the Company still sought to recover all of the costs presently in the transition charge, and to do so by 2009, the transition charge for the years 1999 through 2009 would have to increase substantially. This would make it that much harder for the Company to collect the full transition charge and to still preserve the economic benefit of the 10% rate reduction by staying within the inflation cap specified in the Act. By stretching the securitization payments beyond 2009, the transition charges for the years 1999 - 2009 are reduced, but the customers pay for this, with interest, in higher transition charges subsequent to 2009. Without this stretch out of the recovery of the fixed costs in the transition charge, it would be even more difficult for the Company to keep its rates within the inflation cap during the standard offer transition period.

3. <u>Nuclear PBR</u>

Q. Have you reviewed the nuclear PBR being proposed by WMECO.

A. Yes. The nuclear PBR will be addressed in the nuclear issues phase of this proceeding.

4. <u>Mitigation Incentive Formula</u>

Q. Has WMECO included a mitigation incentive mechanism in its transition charge formula?

A. Yes. Exhibit 13E, Schedule 1, pages 4 and 4A show the mitigation incentive mechanism that WMECO is proposing for its non-nuclear plant and power contracts, respectively. With regard to the non-nuclear plant, WMECO is proposing that it earn a mitigation incentive of 4% of the divestiture proceeds in excess of the book value of its plant. With regard to the power contracts, WMECO is proposing that it earn an incentive of 4% of the amount by which the actual above market costs of the purchased power contracts are less than the above market costs initially assumed for the purpose of calculating the base transition charge.

Q. Are these mitigation incentives appropriate?

A. No. With regard to the non-nuclear units being divested, the market value has nothing to do with the book value. Therefore, the incentive mechanism should not be based on the difference between market value and book value.

With regard to the power contracts, the 4% mitigation incentive, as it is presented by WMECO, is more of an incentive for overestimating the above market costs of the purchased power contracts than it is an incentive for mitigating the cost of those contracts.

There are two above market purchased power contracts, Masspower and Springfield, of these two, Masspower is the larger contract. The initial estimate of the above market costs of the

Masspower and Springfield purchased power contracts is shown on Exhibit 13E, Schedule 1, pages 9 and 10. Referring to Exhibit 13E, Schedule 1, page 9, it can be seen that the estimated cost for the Masspower contract for 1998 is $24,826,000 for ten months, which is based on an annual cost of $29,791,000, and the forecasted cost for 1999 is $31,491,000. This compares to actual costs for the Masspower contract of $23,714,000 in 1996 and $25,589,000 for 1997. Thus, the annualized rate for 1998 represents an increase of 16% over the total cost in 1997. Further, the cost per kwh for the Masspower generation in 1998 is projected to be approximately 7.4 cents per kwh, an increase of approximately 23.5% over the average rate of 6.0 cents per kwh in 1997. The forecasted cost for 1999 assumes a further increase in the total cost of the Masspower generation and in the cost per kilowatt hour. In addition, the wholesale market prices used by WMECO on Exhibit 13E, Schedule 1, page 10 for the purpose of calculating the above market cost of the Masspower contract appear to be on the low side.

If the actual cost of the Masspower contract is below the cost assumed by WMECO, which appears likely, and the market value of the generation is higher, then the above market cost of the Masspower contract will be lower than the estimate used by WMECO in the calculation of the base transition charge. This would result from nothing more than the high cost and low value assumptions used by WMECO to calculate the above market cost of the Masspower contract. Yet, for this, WMECO would earn a mitigation incentive. The reward would be not for actually doing anything to mitigate the above market cost, but rather using high cost and low value assumptions to begin with.

Q. Should the mitigation incentive proposed by WMECO be modified?

A. Yes. The settlements with MECO, EECO and BECO all use the same formula for calculating the cost of equity component included in the carrying costs that are part of the transition charge. Because this formula pegs the ultimate return on equity recoverable by the Company to the cumulative average transition charge, this return on equity formula provides a comprehensive incentive to the Company to mitigate the transition charge to customers. The Company will achieve a higher return to the extent that it lowers the transition charge and to the extent that it lowers the TC sooner rather than later. The return on equity formula in the settlements does not limit the companies' incentives to mitigating the above market cost of purchased power contracts and/or maximizing divestiture proceeds, but rather rewards the companies for mitigating the transition charge on a comprehensive basis. The mitigation incentive implicit in the return on equity formula in the settlements is the appropriate incentive to include in the TC determination. It is also consistent with the formula specified in the Act, which establishes a maximum allowable return on equity to be included in any return component of the TC. In fact, except for the last ten words in Section 1G(b)(3)(c), the formula in the settlements is exactly the same as the formula in the Act.

Q. Could you demonstrate how the return on equity formula in the Act provides an appropriate incentive to mitigate the transition charges?

A. Yes. The Act provides that if the cumulative average of the TC is less than $0.01, the Company can earn a 12% return on equity as part of any return component included in the transition charge; if the TC is between $0.01 and $0.02, then that return is reduced by one basis point for each $.0001 that the TC is above $0.01; and if the TC is more than $0.02, then the return is further reduced by two basis points for each $0.0001 that the TC is above $0.02.

Thus, for example, if a Company's cumulative average transition charge were $0.02 over a given period, it would earn an incentive reward equal to 200 basis points on common equity as compared to what would be recovered if its cumulative average transition charge were $0.03 over that same period. Pursuant to this formula, a company can earn more, or less, than its cost of equity, depending on how successful it is in mitigating the transition charge.

With regard to MECO, EECO, and BECO the effect of using this formula for the mitigation incentive can be seen in the schedules accompanying the settlements. The starting point for the return on equity is based on the formula in the Act (again, except for those ten words referred to above). Then as the cumulative average of the TC is reduced, an incentive reward is earned. The effect of the incentive is to increase the return on equity component of the transition charge.

Q. What does this formula accomplish?

A. Very simply, it rewards electric utility companies that are successful in mitigating their transition charges and penalizes those companies with higher transition charges and does so in a way that is fair and equal for all companies undergoing restructuring. However, if each company is free to choose its own mechanism, then it should be obvious that this goal is defeated. What we are left with is the prospect of companies with higher transition charges earning greater incentives, not because they actually earn those greater incentives, but rather because they are free to design "incentive" mechanisms to their own advantage, with rewards that have nothing to do with actually mitigating the transition charges.

Q. What do you recommend?

A. Pursuant to the formula adopted in the MECO, EECO, and BECO settlements, the lower the transition charge, the higher the return on common equity included in the carrying charges. This provides an appropriate incentive mechanism to mitigate transition charges. By calculating the return on common equity pursuant to this formula, the Company would be given a proper incentive to mitigate its transition costs on a comprehensive basis. This is the mitigation incentive that should be included in the transition charge formula. As it is the mitigation incentive included in the transition charge formulae for MECO, EECO, and BECO, it should also be the mitigation incentive that is included in the WMECO transition charge formula.

Q. Does this conclude your testimony?

A. Yes.